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October - December 1996 Quarterly Report

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Disclaimer

Fourth Quarter, 1996: Initial Commercial Operation:

Ten gasifier runs totaling 701 hours were made in October and November, 1996, prior to a planned outage which began December 5 for routine maintenance, inspections, and some minor improvements. In the 30 days preceding the outage, the gasifier was on-line 67% of the time and the gas turbine was on 100% syngas fuel 59% of the time. This was a major accomplishment which exceeded our target expectations for this period. The longest continuous gasifier run was 7.5 days, and the combustion turbine was on syngas fuel continuously for 7.3 days during this run. The last four gasifier runs were shut down by transmission system voltage swings external to the plant. The protections systems have been reconfigured so even minor external disturbances such as these will no longer trip the unit. These runs are summarized in Table 1.

TABLE 1
Gasifier Runs, Shutdown Causes
Early Commercial Operation (October, November and December, 1996)

Run Number	Duration (Hours)	Turbine On Syngas (Hours)	Shutdown Cause
11	31.2	2.8	Convective SGC Plugging
12	101.6	16.8	Combustion Turbine Vibration-Rotor Bolt
13	81.9	51.4	Steam Turbine Trip (Excitation) Caused BFW Loss
14	4.5	0.0	Lockhopper Problems
15	54.2	40.4	Steam Turbine Trip (Excitation) Caused SGC Drum Upset
16	17.9	0.0	Main Air Compressor Trip - Execution of DCS Change
17	153.8	149.0	Oxygen Compressor Trip - Transmission System Voltage Swing
18	4.5	0.0	Slurry Feed Pump Trip - Transmission System Voltage Swing
19	71.0	64.6	Main Air Compressor Trip - Transmission System Voltage Swing
20	180.1	174.7	Slurry Feed Pump Trip - Transmission System Voltage Swing
21	33.3	5.9	Gasifier trip on low differential pressure between IP steam and gasifier
22	186.5	157.5	Run 22 continued into January of 1997. Hours shown are for 1996 only.
Total	**920.5**	**663.1**	

Specific operational experiences and challenges during the commissioning and initial commercial operational phases are detailed below.

AIR SEPARATION

The oxygen plant has operated essentially trouble free through both the commissioning and initial commercial operational phases. Early high vibration of the main air compressor motor has been reduced to normal levels. Three recent gasifier trips have resulted from oxygen plant trips due to problems external to the oxygen plant itself. Polk Power Station does not have a backup liquid oxygen supply system which could have saved these gasifier runs. When backup systems were being evaluated in the design phase, their cost could not be justified based on the expected incremental availability they were expected to provide. This is probably still the case, but TEC will continue to monitor the frequency of ASU plant trips.

The process performance of the oxygen plant has been exceptionally good. It comfortably met its rated production under hot ambient conditions with all product purities better than design and with capacity still available on the columns, exchangers, and compressors. Power consumption appears to be generally consistent with our expectations, but because of the number of variables involved, it must still be checked during a detailed performance test.

The advanced controls handle minor perturbations around steady state well, and we now always operate with them engaged. They adjust the feed air flow and internal flows based on the demand for the various products.

SLURRY PREPARATION

Slurry preparation performed extremely well during the commissioning phase. For three months, we produced stable, pumpable slurries up to 64% concentration without the use of additives with virtually no operational problems. Early high vibration of the rod mills was quickly eliminated by reinforcing the foundations. However, some severe problems did develop beginning early in the fourth quarter of 1996. Specifically, we observed:

- Settling and partial plugging in many horizontal piping runs (reduced pumping capacity and caused instrumentation problems)
- Severe liner wear on the slurry transfer pumps (reduced pumping capacity)
- Overflowing of the slurry screens (operational problems)
- pH swings in the product slurry (corrosion of tanks and piping)
- Failure of the purge water filter (operational problems)

Factors which may have contributed to some or all of these problems are as follows:

- Variations in feed coal properties have been observed. Distinct property variations in the off-site coal pile have been documented, apparently due to weathering and/or aging; and aging in the on-site coal storage silos is also likely. This seems to be linked to the pH swings.

- The installed slurry screens are finer than Texaco had specified and the pump manufacturer required. This contributes to the problem of overflowing screens.

- A low dose rate of viscosity reducing additive has been used occasionally. This temporarily facilitates pumping, but may contribute to the line plugging in the long term.

- Rod loading in the mills has been adjusted several times to try to fine tune the particle size distribution.

We are addressing these problems through a series of steps such as installing appropriately sized slurry screens, restoring the initial rod loading of the rod mills, and more carefully monitoring and controlling the slurry pH with ammonia injection. Some additional modifications may be required once these easier changes are completed.

GASIFIER

The gasifier itself is quite simple and it has performed reliably throughout the commissioning and early commercial operational phases.

The gasifier safety system performance has been excellent to date. We have had no nuisance shutdowns - all automatic shutdowns have been the result of problems in other parts of the plant which properly tripped the unit. The gasifier feed controls have also been excellent. These adjust the overall gasifier load as well as the ratio of oxygen to slurry to control gasifier temperature.

Thermocouple life had been a problem in the commissioning phase. However, early in the operational phase, we began running at lower temperatures which prolonged thermocouple life. Also, the on-line analyzers were proven sufficiently reliable and, in parallel, useful correlations between gasifier temperature and the syngas composition were developed. Consequently, although thermocouples are still necessary at times and they must still be replaced more often than we would prefer, concern and expense in this area has been significantly reduced. Additional development work is underway to further increase thermocouple life and reduce cost.

During the commissioning phase, we observed the performance of the gasifier at various temperatures, loads, and slurry concentrations. Some minor feed injector design changes were made as a result. We believe the operating conditions are now near optimum for this feed injector design and refractory liner.

The following Table 3 shows that some aspects of the gasifier's performance at current operating conditions that do not yet meet "Design" or "Commercially Expected" values.

TABLE 3
Slag Characteristics and Refractory Liner Life

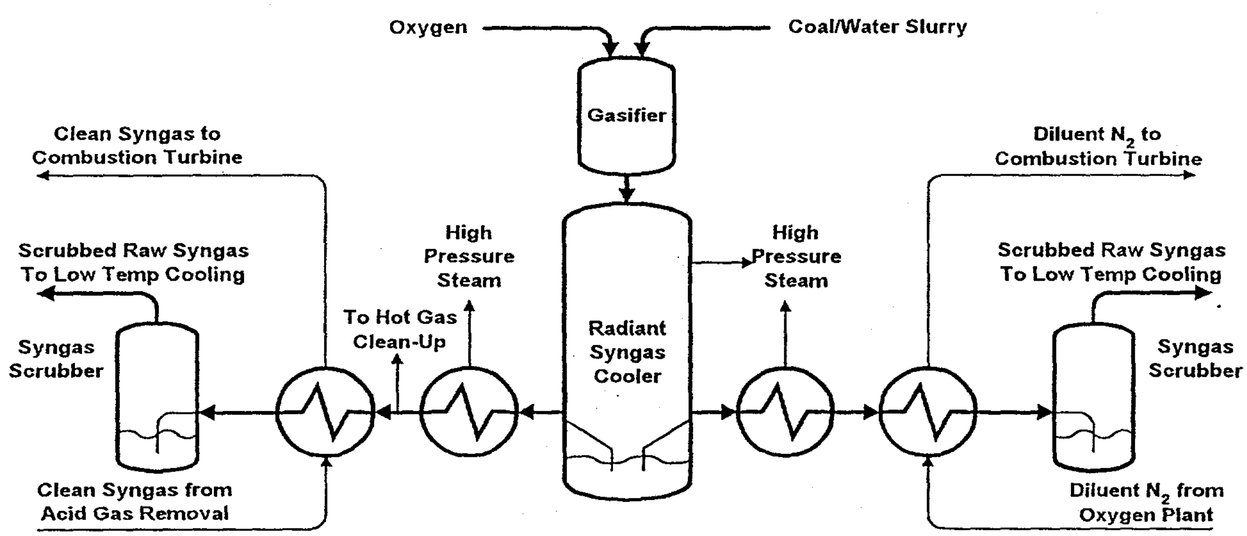
	Current Full Load Operation	Design or Commercial Expectation
Slag Carbon Content (Weight % Dry Basis)	34	14 to 28
Slag Quantity (Dry Tons/Day)	250	185 to 215
Heating Value Lost To Slag (MMBTU/Hr HHV)	70	20 to 50
Refractory Liner Life (Years at 85% On-Stream Factor)	½	2

Carbon conversion can be increased at the expense of refractory liner life, and vice-versa, by adjusting gasifier temperature. However, as can be seen from the table, there is little available to sacrifice on either parameter. The higher than expected carbon content of the slag creates handling problems and makes it a less desirable byproduct for many applications. It also increases the mass and volume of the material we must handle. Furthermore, the heating value of the carbon lost with the slag increases net plant heat rate by 75 to 200 BTU/KWH. The current "startup" gasifier refractory liner is less expensive with reduced slag resistance compared to the material we expect to use long-term. Our first liner replacement is scheduled for the spring of 1997. It will be a more slag-resistant material, so at current operating conditions, it may approach our commercial expectations of a 2 year liner life. However, some additional feed injector adjustments to improve carbon conversion at less severe reactor conditions are still required for us to realize our commercial expectations for liner life, heat rate, and slag quantity/quality. Texaco has an excellent team on-site and at other Texaco engineering and development centers working with us on these issues.

HIGH TEMPERATURE SYNGAS COOLING

High Temperature Syngas Cooling consists of a Radiant Syngas Cooler (RSC) followed by Convective Syngas Coolers (CSC).

FIGURE 2
Syngas Cooler System



Raw syngas from the gasifier first passes downward through an RSC where high pressure steam is generated. The CSC System consists of two wings, each of which handles 50% of the RSC outlet gas. Each wing consists of a fire-tube convective heat exchanger producing high pressure steam, followed by a two stage gas/gas heat exchanger where the raw syngas (tube side) heats either the clean syngas or diluent nitrogen to the combustion turbine.

The RSC and its associated steam systems have been trouble-free through both the commissioning and early operational phases. Fouling factors have been only ⅓ of the design value with Pittsburgh #8 coal, so no soot-blowing has been required. Fouling has been so low that we may need to elevate the RSC outlet temperature by covering part of the RSC surface with insulating refractory to meet the HGCU minimum inlet temperature requirement. Soot blowing may be required as we achieve longer run times and gasify other coals, but all indications are that we will have no difficulty achieving target heat transfer. There have been no hints of plugging in the RSC.

As with the RSC, heat transfer in the CSC exchangers has recently been excellent. Fouling factors have been 30% or less of design values where we could measure them.

One of the greater challenges during the commissioning phase was pluggage within the CSC system. Many of the gas/gas exchanger tubes plugged with ash deposits during several of the commissioning phase runs. This increased the pressure drop above the allowable level, so it was necessary to cool, open, enter, and clean this equipment often. The deposits absorbed moisture during this downtime, some from the ambient air and some from other sources. This produced rapid downtime corrosion. Pits penetrated through up to 60% of the tube wall thickness in some places. Fortunately, very early in the operating phase, we learned how to eliminate this plugging by controlling temperatures and velocities in the equipment. Also, we have been more careful in our shutdown and startup practices to minimize conditions leading to downtime corrosion. The inspection during the December, 1996, planned outage revealed no plugged tubes and no increased corrosion.

LOW TEMPERATURE GAS COOLING (LTGC)

Immediately downstream of the CSC's are the Syngas Scrubbers where particulates and chloride are removed from the raw syngas in a water wash. The raw syngas is water saturated as it leaves the scrubbers at about 300°F. The LTGC system cools the syngas to near ambient temperature for the acid gas removal system. As the gas cools, most of the water vapor condenses and becomes what is referred to as process condensate. The LTGC system consists of three partially condensing heat exchangers and associated knock-out drums, the process condensate return system, and an ammonia stripper to rid the system of the ammonia which condenses from the syngas with the process condensate.

The system has generally performed well to date. Some minor modifications were made to accommodate the somewhat different than expected flow rates of process condensate from some of the exchangers. The greatest difficulties have been in the ammonia stripper overhead piping. Ammonia combines with carbon dioxide to form solid salts which plug the piping if the temperature falls below about 160°F. Heat tracing was inadequate in some line segments and it was completely overlooked in others. Furthermore, the piping and control valves were inadequately sized, and this has prevented us from feeding this entire stream to the Sulfuric Acid Plant where the ammonia is to be converted to nitrogen and water vapor. These problems have been corrected and we expect no further difficulty with the LTGC system.

ACID GAS REMOVAL

A tertiary amine (MDEA) system is being used in the Polk plant for removing hydrogen sulfide (H_2S) from the raw syngas in the cold gas clean-up (CGCU) system.

We experienced a significant amount of foaming when we first introduced syngas to the MDEA absorber during Gasifier Run #4 early in the Commissioning Phase. Foaming is a known problem with all amine based acid gas removal systems. We quickly brought this foaming under control with filtration and anti-foam agents and have experienced no foaming during subsequent runs. However, some amine contamination of other plant systems persists, probably through a slight amount of carry-over with the clean syngas during startup. This amine finds its way into the grey water system, and ultimately into the brine concentration unit where it causes foaming in the falling film evaporator. This foaming must also be controlled with anti-foam agents.
Tuning of the MDEA system operation continued through the remainder of the commissioning phase, and clean gas within Polk's environmental requirements was consistently being produced by the beginning of the fourth quarter of 1996. 95% overall sulfur removal is achieved. The MDEA now routinely removes 99% or more of the H_2S. The remainder of the sulfur emissions are derived from carbonyl sulfide (COS), a compound which our plant configuration and MDEA solvent are not designed to remove. The gasifier produces more COS than was expected, and we are hoping the high COS production rate observed to date is peculiar to the Pittsburgh #8 coal we are now running. If it is not, we may have to change solvents, adjust operating conditions, and possibly make other modifications to run higher sulfur coals within our current permit limits.

While the MDEA does remove virtually all the H_2S, it typically only removes about 12% of the carbon dioxide (CO_2) from the syngas. The plant design assumed 20% of the CO_2 would be removed. This extra CO_2 in the syngas improves overall plant efficiency by increasing the "free" mass flow to the turbine and reducing the steam required to regenerate the solvent.

A steady rise in the concentration of degradation products has occurred in the MDEA solvent but not at an unexpected rate. A water wash column is installed upstream of the absorber to remove trace compounds to minimize formation of these MDEA degradation products. We have not yet built sufficient operating history to evaluate its effectiveness.

SULFURIC ACID PLANT

The Acid Gas Removal system produces the main feed stream for the Sulfuric Acid Plant, an acid gas stream consisting of 20% to 30% H_2S and most of the remainder CO_2. The other main feed stream is the Ammonia Stripper off-gas. The Sulfuric Acid Plant has performed very well once steady, efficient operation of the Acid Gas Removal system was achieved early in the fourth quarter. The plant has tripped four times due to pressure fluctuations of the feed streams. These were not related to the Acid Plant itself.

The Pittsburgh #8 coal we are currently gasifying has a sulfur content of less than 2.5%, compared to a design concentration of 3.5%. As a result, 1 to 2 MMBTU/Hr of supplemental fuel is sometimes required as expected to maintain temperature in the catalytic reactors.

SLAG HANDLING, FINES REMOVAL, AND PROCESS WATER SYSTEMS

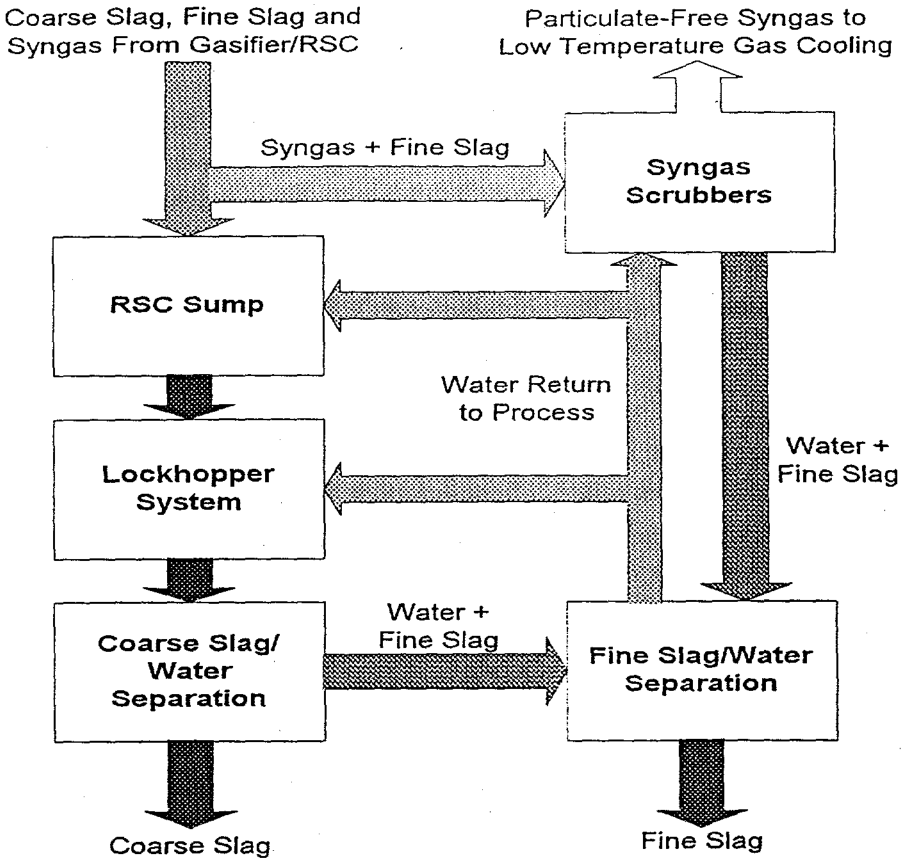


FIGURE 3
Process Water Systems, Fine and Coarse Slag Handling

Coarse slag and some of the fine slag from the gasifier falls through the RSC into a water pool at the bottom. This pool is referred to as the RSC Sump. From there, the slag is removed via a lockhopper system which cycles approximately twice per hour. With each cycle, the water and slag mixture from the lockhopper dumps into a concrete holding area where it is separated (Coarse Slag/Water Separation). The coarse slag is hauled to the slag holding area. The water, containing some fine slag, is pumped to the Fine Slag/Water Separation System.

The fine slag which does not fall into the RSC sump passes through the CSC system with the syngas and is removed in the syngas scrubbers. Fine slag and water are continuously blown down from the scrubbers. This stream is also routed to the Fine Slag/Water Separation system.

Fine Slag/Water Separation consists first of a settler where the fines are concentrated. The fines in the settler bottoms are then removed in a rotary drum vacuum filter and are also hauled to the slag holding area. The water is returned to the process.

The fines removal system has performed beyond expectations. It typically handles much more water and fines than design. During the commissioning phase, upsets of the settler did occur due to excessive traffic and/or loss of polymer feeds. This led to solids carryover from the gravity settler, resulting in plugged process piping. These problems have been largely eliminated in early commercial operation with operating experience.

Likewise, the lockhopper, RSC sump, and syngas scrubbers also experienced some plugging in the Commissioning Phase during periods of excessive solids traffic, but these problems also have been resolved with experience and some minor piping modifications. Erosion has been encountered in some control stations during early commercial operation. This was not unexpected, and it is being addressed with materials and configuration changes.

The Coarse Slag/Water Separation system has been a challenge. The water was expected to easily separate from the slag in the concrete holding area after each lockhopper dump. However, the fine slag stayed in suspension. These fines plugged the local sump and increased the loading on the gravity settler. Barrier walls were installed in the slag holding area and the water is now pumped off in batches after settling. This added settling time greatly reduces the fine slag in the water. The system is now operable, but still very labor intensive. Significant configuration changes are being considered for the long term.

BRINE CONCENTRATION

The Polk Power station is permitted as a zero process water discharge facility requiring that all of the process water is recovered and reused. Through recycling, the chlorides removed from the syngas in the Syngas Scrubber would build to unacceptably high levels for affordable metallurgy. Therefore, a brine concentration system was incorporated into the plant design. It consists of a falling film evaporator, followed by a forced circulation evaporator feeding a crystallization and centrifuge separation step.

During the third quarter, the falling film unit was commissioned with excellent results. As previously mentioned, foaming problems resulting from amine in the feed has resulted in the greatest operational problems such as sump level control and carryover. Anti-foam agents have been effective, and a permanent anti-foaming injection system is being pursued.

The forced circulation evaporator has been the greatest challenge in operating the brine concentration unit in the early commercial phase. Corrosion has been excessive. Using corrosion coupon tests, coupled with laboratory tests, the corrosion mechanism is being understood which will lead to metallurgical and process modifications in this system.

Control of the centrifuge has been difficult, resulting in crystals of variable quality. We believe this is due in large part to erratic flows causing periodic line pluggage. The control scheme is being modified.

COMBINED CYCLE

The key components of the combined cycle are the advanced combustion turbine (CT), heat recovery steam generator (HRSG), steam turbine (ST), and electric generators. The combined cycle power plant was provided by General Electric.

The CT is a modified Frame 7F capable of producing 150 MW (gross) from #2 fuel oil (the startup and backup fuel) and 192 MW (gross) from syngas fuel. When firing syngas fuel, nitrogen from the ASU provides both NO_x abatement and power augmentation.

Hot exhaust from the CT is channeled through the HRSG to recover energy. The HRSG performs most of the plant's economizing and all of the superheating, while most of the high pressure steam is generated in the syngas coolers when the gasifier is on line. The HRSG also produces much of the low pressure steam consumed by the gasification plant. Consequently, Polk's HRSG contains significantly more superheater, economizer, and low pressure evaporator surface compared to HRSGs in conventional combined cycles.

The 130 MW ST is a double-flow reheat turbine. Nominal turbine inlet steam conditions are 1450 psig and 1000°F with 1000°F reheat temperature. Low pressure extraction provides the remainder of the low pressure steam for the gasification plant.

The combined cycle was commissioned on May 4, 1996. Ever since, it has been dispatched as a normal Tampa Electric generation resource. It has produced approximately 150,000 megawatt hours on distillate fuel and 200,000 megawatt hours on syngas fuel through the end of 1996.

The combustion turbine was first operated on 100 percent syngas fuel for 4.1 hours during Gasifier Run #10 in mid September. It reached a maximum load of 161 MW on syngas, generating 520 megawatt hours over this period. Combined cycle output reached 210 MW. However, this first period of operation on syngas revealed a design problem with the fuel nozzles which led to some local overheating. The combined cycle was out of service for the remainder of September for repairs and modifications. This problem has not recurred.

A brief period of operation on syngas fuel occurred during a short gasifier run on October 1. During the next gasifier run, Run 12, the CT reached full syngas load (192 MW gross) on October 13. This run was highly successful, but it did identify two additional problems:

1) Performance data during this run showed that the diluent nitrogen control valve was undersized for the design flow. Diluent N_2 is used for NO_x abatement, and sufficient N_2 could only be provided to keep NO_x emissions within permit limits with a CT output of 185 MW (gross). A larger valve is due in February, 1997.

2) GE observed high CT vibration on October 16. Their on-line diagnostics showed this was caused by a crack in a large turbine rotor bolt. GE replaced all these bolts in the subsequent 11 day outage. The CT has had no further high vibration problems.

ST excitation system failures caused ST trips on October 31 and November 6. These led to gasifier trips due to an incorrect valve lineup in the Hot Gas Cleanup System which had not yet been commissioned. These trips clearly demonstrate some of the drawbacks of integration: problems in one process unit can create even greater problems in another. The valve lineup was quickly corrected once it was found, and subsequent ST trips have not caused gasifier trips. We believe we have also finally found and corrected the cause of ST excitation system failures.

The best combined cycle performance prior to the December planned outage occurred during gasifier Run 20 from November 26 to December 4. The gasifier was on line continuously for 180 hours and the CT was on syngas fuel continuously for 175 hours. The average gross power production for the entire period was 300 MW, 184 MW from the CT and 116 MW from the ST.

At the time of printing of this paper, Gasifier Run #22 was still in progress. Through January 5, the gasifier had been on-line continuously for 306 hours and the CT had been on syngas fuel for a total of 296 hours and continuously for 267 hours.

Starting reliability of the CT on distillate fuel has been good, but fuel transfers to syngas fuel have been inconsistent. The first attempts to transfer the combustion turbine to syngas fuel in August were unsuccessful. Corrections were made, and the next attempt in mid-September went smoothly. But new problems appeared and there were 3 failed transfer attempts during gasifier Run 16 in early November. The CT never successfully transferred to syngas fuel in 18 hours of gasifier operation during that run. However, in mid and late November, transfers were smooth and routine. The purge system and the CT control system were modified in the December outage. Despite the changes, fuel transfers again were problematic in late December. We are hoping for a speedy resolution once all purge system modifications are completed and the controls are retuned.

CONTROL SYSTEM

The plant's main control system is a Bailey Infi-90 Distributed Control System (DCS). The DCS communicates directly with 3 other plant control systems: the CT GE Mark V, the ST GE Mark V, and the Triconex Gasifier Safety System. There are about 7200 direct Input/Output variables. Over 500 process control graphics available on any of 14 CRT screens provide the operator interface.

The DCS has performed well. No gasifier or plant trips have been caused by DCS module or I/O failures. The overall DCS availability in fourth quarter of 1996 was 100.0 %.

Two systems associated with the DCS have also been highly successful: 1) the data storage, and 2) retrieval system and the operator training simulator. It is not an exaggeration to say that the Polk plant would not be running as well as it is today without these systems.

- Data storage and retrieval is done by a product called Plant Information Systems (PI) from Oil Systems Inc. Data storage has been almost 100% reliable, and retrieval is easy in several different formats (graphs, tables, spreadsheets).

- The operator training simulator was furnished by Bailey and TRAX, Inc. A copy of the actual plant control system (DCS and Triconex hardware and software) interacts with process plant models running on seven PC's. This simulator enabled plant personnel to become familiar with plant operation before startup and correct control system and procedural errors before they occurred in the real plant.

Although the DCS has performed well, the required level of technical support has been higher than expected to achieve these results. A full-time team of seven with some supplemental help worked throughout most of 1996 to address the following issues:

- DCS module infant mortality was fairly high in the Commissioning Phase, but failure rates have declined dramatically. All failed modules were replaced under warranty.

- Initially there were over 8000 possible alarms, and at times during the Commissioning Phase over 1000 of these were simultaneously active. Such information overload causes alarms to be ignored. A separate "alarm team", formed late in the Commissioning Phase, reduced the number of alarms to about 4000. Further reduction in the number of possible alarms and prioritization of the remaining alarms is still in progress.

- Conveying information which can be quickly and easily interpreted for split-second decision making is always a challenge. To meet this challenge, it has been necessary to improve plant diagnostics by adding more "first out" indications, dedicated displays, and ready lists. Graphic displays have also been modified to be more concise and easily readable. These efforts will undoubtedly continue into the foreseeable future.

- The data links between the DCS and both CT and ST Mark V control systems have been troublesome. Making changes is particularly hard. (In contrast, the data link between the DCS and the Triconex Gasifier Safety System has worked very well.) Also, working on the Mark V and GE's user interface is difficult. We must still rely more heavily on GE than we would prefer at this stage of operation. It would have been preferable to have done as many of the turbine control functions as possible directly in the DCS.

- Almost all logic and configuration errors have been eliminated, initial tuning has been done on all control loops, and some optimization has been done. However, initial operation and tuning efforts have shown that new or modified control logic will be necessary for several plant areas such as:

  -- Overall plant load control
  -- Combustion Turbine fuel transfers,
  -- pH control in water treatment,
  -- Grey Water inventory control
  -- Centrifuge control in Brine Concentration.

As an example, plant load changes are difficult due to the high degree of integration. Load changes involve the syngas and O_2 header pressure controls, and gasifier, Oxygen Plant, CT, and ST load controls. Currently, it is not possible for us to make large station load changes with the overall plant load control engaged due to the disparate and often large time constants of the systems involved. This is currently not a serious problem, since Polk is normally base loaded due to its high efficiency.